PB87-175832

Estimating Performance/Costs of Retrofitting Control Technologies at Twelve Coal-Fired Power Plants

(U.S.) Radian Corp., Research Triangle Park, NC

Prepared for

Environmental Protection Agency
Research Triangle Park, NC

Mar 87

U.S. Department of Commerce
National Technical Information Service
NTIS

PB87-175832

EPA/600/D-87/106
March 1987

ESTIMATING PERFORMANCE/COSTS OF RETROFITTING CONTROL TECHNOLOGIES AT 12 COAL-FIRED POWER PLANTS

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EPA Contract 68-02-3994

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SPRINGFIELD, VA 22161

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO.	2.	3. RECIPIENT'S ACCESSION NO.
EPA/600/D-87/106		PB87 175832/AS

4. TITLE AND SUBTITLE	5. REPORT DATE
Estimating Performance/Costs of Retrofitting Control Technologies at 12 Coal-Fired Power Plants	March 1987
	6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S)	8. PERFORMING ORGANIZATION REPORT NO.
J. W. Jones (EPA/AEERL), T. E. Emmel (Radian), and B. A. Laseke (PEI Associates)	
9. PERFORMING ORGANIZATION NAME AND ADDRESS	10. PROGRAM ELEMENT NO.
Radian Corp, P. O. Box 13000, Research Triangle Park, NC 27709; and PEI Associates, Inc., P. O. Box 46100, Cincinnati, OH 45246	11. CONTRACT/GRANT NO. 68-02-3994 (Radian); and 68-02-3995 (PEI Assoc.)
12. SPONSORING AGENCY NAME AND ADDRESS	13. TYPE OF REPORT AND PERIOD COVERED
EPA, Office of Research and Development Air and Energy Engineering Research Laboratory Research Triangle Park, NC 27711	Published paper; 11/85-2/87
	14. SPONSORING AGENCY CODE EPA/600/13

15. SUPPLEMENTARY NOTES

16. ABSTRACT The paper gives results of estimating performance/costs of retrofitting pollution control technologies at 12 coal-fired power plants. In cooperation with the states of Ohio and Kentucky (in conjunction with EPA's state acid rain program), efforts were undertaken to visit and conduct detailed evaluations of 12 coal-fired plants--5 in Ohio and 7 in Kentucky and the Tennessee Valley Authority system. A variety of commercial and advanced SO2 and NOx control technologies--including precombustion, combustion (in-furnace), and post-combustion (flue gas cleanup) technologies--were applied to each plant through conceptual designs. Retrofit factors (applied to the capital cost of a new pollution control system), cost adders (e.g., movement of existing equipment), and costs were developed for applying the control technologies to the boilers of each plant. Results of these and subsequent efforts will be valuable in evaluations of acid deposition control strategies by federal and state agencies and by electric utilities.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Pollution	Nitrogen Oxides	Pollution Control	13B
Estimating	Flue Gases	Stationary Sources	14G
Cost Estimates	Boilers	Acid Rain	14A, 05A 13A
Electric Power Plants			10B
Coal	Precipitation (Meteorology)		21D
Combustion			21B 04B
Sulfur Dioxide	Acidification		07B 07C

18. DISTRIBUTION STATEMENT	19. SECURITY CLASS (This Report)	21. NO. OF PAGES
Release to Public	Unclassified	19
	20. SECURITY CLASS (This page) Unclassified	22. PRICE

EPA Form 2220-1 (9-73)

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INTRODUCTION

One of the responsibilities of the National Acid Precipitation Assessment Program (NAPAP) is to develop cost and performance information on various methods for reducing the emissions of acid rain precursors. A major factor affecting the cost and performance of SO_2 and NO_x controls for coal-fired power plants is the degree of difficulty associated with retrofitting controls at existing boilers. This paper presents results from an ongoing program conducted under NAPAP by the U.S. EPA's Air and Energy Engineering Research Laboratory. The objective of this research program is to significantly improve engineering cost estimates currently being used to evaluate the economic effects of applying SO_2 and NO_x controls to existing coal-fired utility boilers.

In the initial phase of the program, procedures were developed: to select plants with boilers representative of the population, to conduct plant visits and collect site-specific data, to develop boiler/control-specific retrofit difficulty factors, and to develop boiler/plant-specific cost and performance estimates for the SO_2 and NO_x controls selected for evaluation. The performance and cost estimating process is dynamic: it incorporates recommendations from a technical advisory group and participating utilities, and experience from site visits and performance/cost evaluations.

A number of commercial and developmental SO_2 and NO_x control technologies were selected for inclusion in the program; these are listed in Table I. Control technologies reviewed but not selected include integrated gasification/combined cycle, chemical coal cleaning, pressurized fluidized bed combustion, and advanced SO_2/NO_x (combined) control devices. These were not included because of general inapplicability to retrofit situations, early development status, and/or limited cost/performance information.

TABLE I. EMISSION CONTROL TECHNIQUES SELECTED

Control Technique	Species Controlled		Development Status		
	SO_2	NO_x	Commercial	Limited Commercial Experience	Near Commercial Demonstration
Lime/limestone (L/LS) flue gas desulfurization (FGD)	X		X		
Additive enhanced L/LS FGD	X		X		
Lime spray drying (LSD) FGD	X		X		
Physical coal cleaning (PCC)	X		X		
Coal switching and blending (CS/B)	X		X		
Low-NO_x combustion (LNC)		X		X	
Selective catalytic reduction (SCR)		X		X	
LIMB[a] (furnace sorbent injection)	X				X
Duct sorbent injection	X				X
Natural gas reburning (NGR)	X	X			X
Early retirement/life extension	X	X	NA[b]	NA[b]	NA[b]
Fluidized bed combustion (FBC) repowering	X	X			X

[a]LIMB - Limestone injection multistage burners.
[b]N/A - not applicable; use of this technique is a management decision.

Thirty plants which appeared to be representative of the "top 200" SO_2-emitting plants (based on 1980 emissions) were preliminarily selected for detailed study. At this point in the program, 12 of these plants have been visited: 5 in Ohio and 7 in Kentucky and the Tennessee Valley Authority (TVA) system (which includes Tennessee and portions of Alabama and Kentucky). Cost/performance estimates of the five Ohio plants have been completed, while the Kentucky/TVA plants are still being evaluated. The estimates for all 12 plants are expected to be completed in the spring of 1987.

This paper summarizes the selection of plants for study, the evaluation performance/cost models to be used in these studies, the plant visitation and data gathering process, and the current results of the performance/cost estimating efforts.

PLANT SELECTION

Three key criteria were used in developing the methodology for plant selection. First, plant selection should emphasize boiler types and sizes accounting for the majority of SO_2 emissions. Second, within the limits of the first criterion, the selected plants should be "representative"; i.e., they should not unduly over- or underrepresent the diversity of boiler characteristics and location of the total boiler population. Third, the number of plants to be selected should be limited to 25-30, consistent with the first two criteria, by giving preference to plants containing multiple boilers of diverse types.

Boilers in the top 200 SO_2-emitting plants were categorized by generating capacity, coal percent sulfur, firing type, age, and capacity factor. Plants in the top 200 population were ranked according to their diversity, then the boiler categories represented by the 30 highest-scoring plants were evaluated to see if these plants represented a proportional sample of the entire top 200 population. Plants near the bottom of the list of 30, whose boilers caused categories to be over- or underrepresented, were replaced by plants which improved the representativeness of the sample. Ultimately, a preliminary list of 30 plants was completed. The 12 plants selected for Ohio, Kentucky, and the TVA system and their characteristics are listed in Tables II and III.

COST/PERFORMANCE MODELS

Many of the performance predictions and most of the cost estimates were developed using computer-based simulation models. This approach was taken because of the large quantity of data which must be accessed, used in computation, and stored. A number of mainframe and personal computer-based models were evaluated prior to the selection of those to be used. The Integrated Air Pollution Control Systems (IAPCS) model1, because of its versatility, has become the "workhorse" model under this study. The IAPCS model has been upgraded to include most of the technologies being applied in this program (see Table I).

TABLE II. OHIO PLANT/BOILER CHARACTERISTICS

Plant Name	Generating Unit No.	Unit Net Dependable Generating Capacity, MW	Age, yr	Capacity Factor, percent	Coal Sulfur, percent	Firing Type	FGD Retrofit Difficulty Factor[a] L/LS[b]	FGD Retrofit Difficulty Factor[a] LSD[c]
Burger	1-2	60	40-43	29-30	3.4	Roof	1.27	1.33
	3	90	37	31	3.4	Roof	1.27	1.33
	4-5	150	32	38-56	3.4	Wall	1.22	1.15
Conesville	1-2	125	28-30	32-36	2.9	Cyclone	1.53	1.49
	3	165	25	37	2.9	Wall	1.55	1.48
	4	720	14	58	2.9	Tangential	1.42	1.83
	5-6	375	9-11	45-48	4.1	Tangential	NA[d]	NA
Muskingum River	1-2	205	33-34	63	4.4	Wall (wet bottom)	2.65	1.91
	3-4	215	29-30	55	4.4	Cyclone	1.65	1.91
	5	585	19	61	4.4	Wall	1.53	1.53
Sammis	1-4	180	25-28	44-57	0.9	Wall	NA[e]	NA
	5	300	20	53	2.4	Wall	NA	NA
	6	600	18	51	2.4	Wall	3.0	NA
	7	600	16	44	2.4	Wall	1.8	1.64
Stuart	1-4	559	13-17	56-66	1.2	Wall (cell burner)	1.51-1.54	1.55-1.58

[a]This factor is multiplied times the capital cost of a new FGD system to obtain the capital cost of a retrofit FGD system

[b]L/LS = Lime/limestone flue gas desulfurization (FGD)

[c]LSD = Lime spray drying FGD

[d]NA = Not Applicable; Units 5 & 6 at Conesville already have FGD systems

[e]Severe spatial limitations at Sammis prevent application of FGD on most units

TABLE III. KENTUCKY AND TVA PLANT/BOILER CHARACTERISTICS

Plant Name	Generating Unit No.	Unit Net Dependable Generating Capacity, MW	Age, yr	Capacity Factor, percent	Coal Sulfur, percent	Firing Type	FGD Retrofit Difficulty[a] L/LS[b]	FGD Retrofit Difficulty[a] LSD[b]
Brown	1	100	30	50	1.9	Wall	1.63	1.94
	2	156	24	65	1.9	Tangential	1.51	1.75
	3	410	16	65	1.9	Tangential	1.38	1.23
Elmer Smith	1	151	23	30	2.9	Cyclone	1.66	1.88[c]
	2	265	13	50	2.9	Tangential	1.26	1.64[c]
Big Sandy	1	260	24	63	1.2	Wall	1.50	1.55
	2	800	18	63	1.2	Wall	1.54	1.75[c]
Colbert	1-4	200	32	50	2.3	Wall	1.54	1.50
	5	550	22	50	2.3	Wall	1.38	1.30
Johnsonville	1-4	125	35-36	39	1.7	Tangential		
	5-6	147	34-35	30	1.7	Tangential	1.34[d]	1.66[d]
	7-10	173	28-29	41	1.7	Wall		
Cumberland	1	1300	14	60	2.9	Wall	1.38	1.66
	2	1300	14	60	2.9	Wall	1.26	1.34
Paradise	1	704	24	30	2.9	Cyclone	NA[e]	NA
	2	704	24	30	2.9	Cyclone	NA	NA
	3	1150	17	30	2.9	Cyclone	1.32	1.21

[a]This factor is multiplied times the capital cost of a new FGD system to obtain the capital cost of a retrofit FGD system

[b]L/LS = Lime/limestone flue gas desulfurization (FGD); LSD = Lime spray drying FGD

[c]Based on addition of a baghouse for particulate control; existing electrostatic precipitators inadequate or unusable with LSD

[d]Based on combination of all 10 units at Johnsonville; individual units not evaluated for FGD retrofit

[e]NA = Not Applicable; Units 1 and 2 at Paradise already have FGD systems

PLANT VISITATION/DATA GATHERING

Prior to visiting one of the plants to be studied, a plant "profile" is completed to the extent possible using sources of public information, with primary emphasis on Department of Energy (DOE) Energy Information Agency (EIA) Form 767. The plant profile is designed to include all of the information and data needed for the performance/cost analyses, with the exception of plot plans and boiler drawings. The preliminary plant profiles are typically sent to the utility for review and comment prior to the plant visit; the profile is completed using information obtained during the visit. The plant visits take about one day of discussions with plant personnel and a tour of key portions of the plant.

CURRENT PERFORMANCE/COST ESTIMATING RESULTS

Ohio Plants

Using the data and information obtained through visits to five coal-fired power plants in Ohio, retrofit factors were developed for those technologies which are typically based on the cost of new installations (e.g., FGD, LSD, SCR). These factors are estimated using site-specific location and difficulty factors as well as "cost adders" which involve items not normally included in new plant costs, such as a new chimney or demolition/replacement of existing buildings. The procedures used to develop FGD retrofit factors were developed by the Electric Power Research Institute (EPRI)[2]; application of these procedures to evaluate FGD applications in this study was described in a previous paper[3].

A similar approach was used for the remaining "new-plant-basis" technologies. Using the retrofit factors and the new plant costs, cost estimates were developed for applying these technologies, when feasible, on a (generating) unit-by-unit basis throughout each plant. Similarly, technologies for which retrofit costs are normally calculated directly (e.g., LIMB) were estimated for each plant. The economic premises for the cost estimates were based on the EPRI Technical Assessment Guide (TAG)[4].

Selected performance/cost estimates for applying six of the technologies to the five Ohio plants are shown in Figures 1-6. In each figure the levelized annual revenue requirements, in current dollars (August 1986 basis), are plotted as a function of the quantity of SO_2 or NO_x removed per year. In general, each point on a curve for a particular plant represents one of the generating units for that plant. (There are two exceptions. First, Burger generating Units 1-3 are each served by a pair of identical boilers; i.e., eight boilers serve five generating units. Each point on a curve for Burger represents a boiler. Second, in Figure 2, the points on the curves for Burger, Conesville, and Muskingum River represent FGD systems for combinations of generating units.) The first point on each curve represents the generating unit(s) for which application of the particular technology is most cost-effective. The second point represents the next best cost-effective application, etc. until all of the units

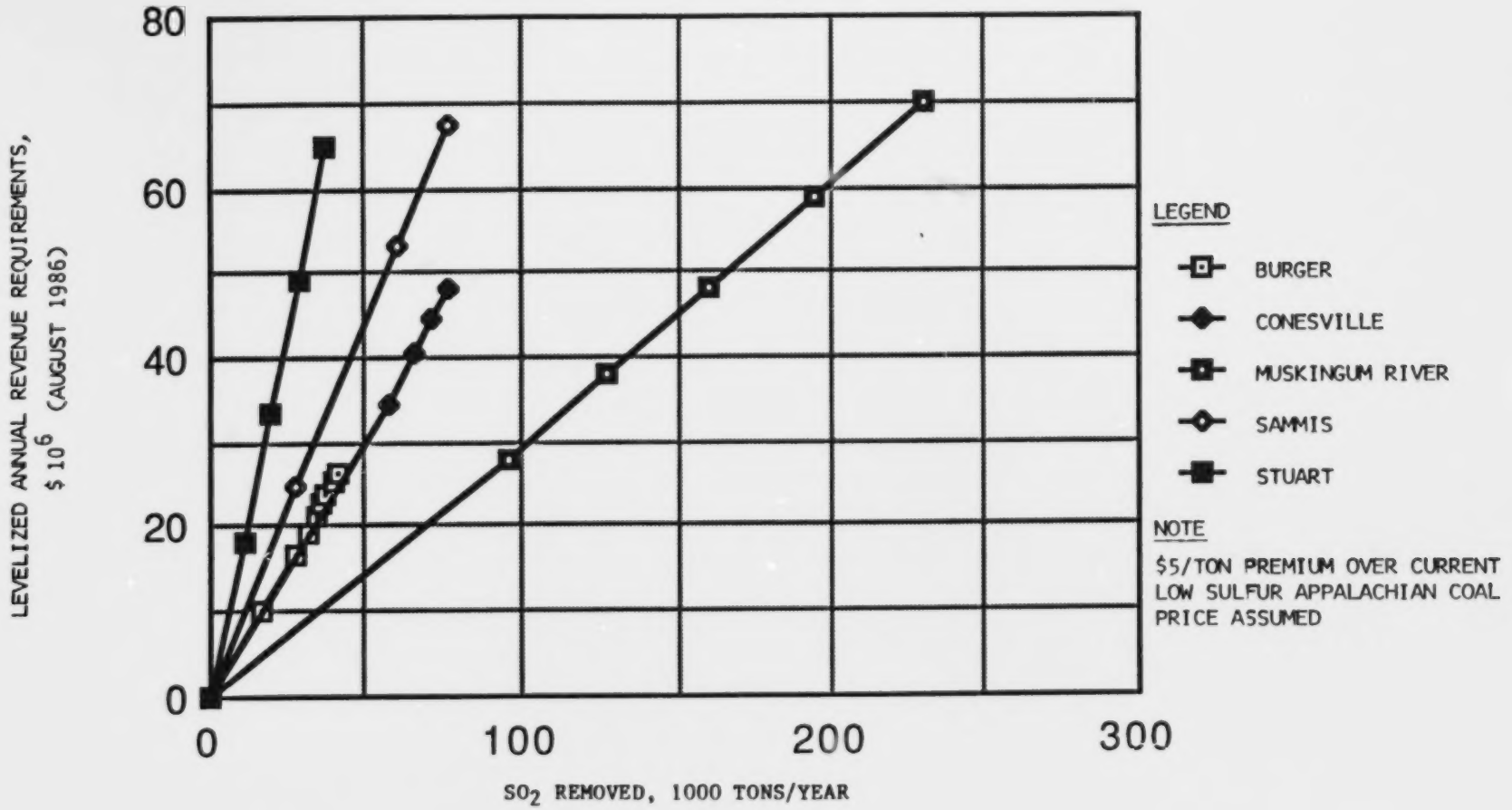

FIGURE 1. PERFORMANCE/COST ESTIMATES FOR SO_2 EMISSION REDUCTION VIA COAL SWITCHING AT FIVE COAL-FIRED POWER PLANTS IN OHIO

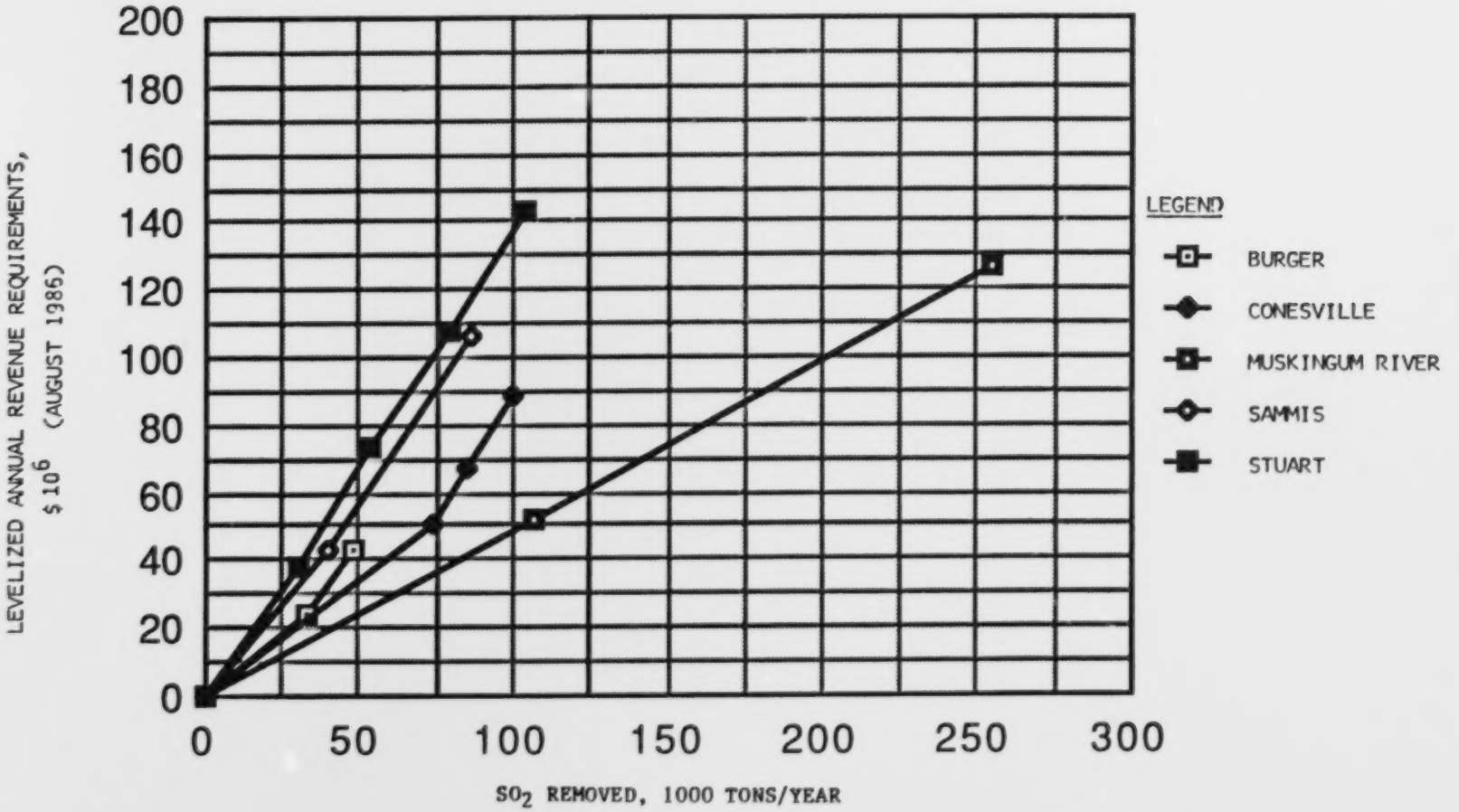

FIGURE 2. PERFORMANCE/COST ESTIMATES FOR SO_2 EMISSION REDUCTION VIA FLUE GAS DESULFURIZATION AT FIVE COAL-FIRED POWER PLANTS IN OHIO

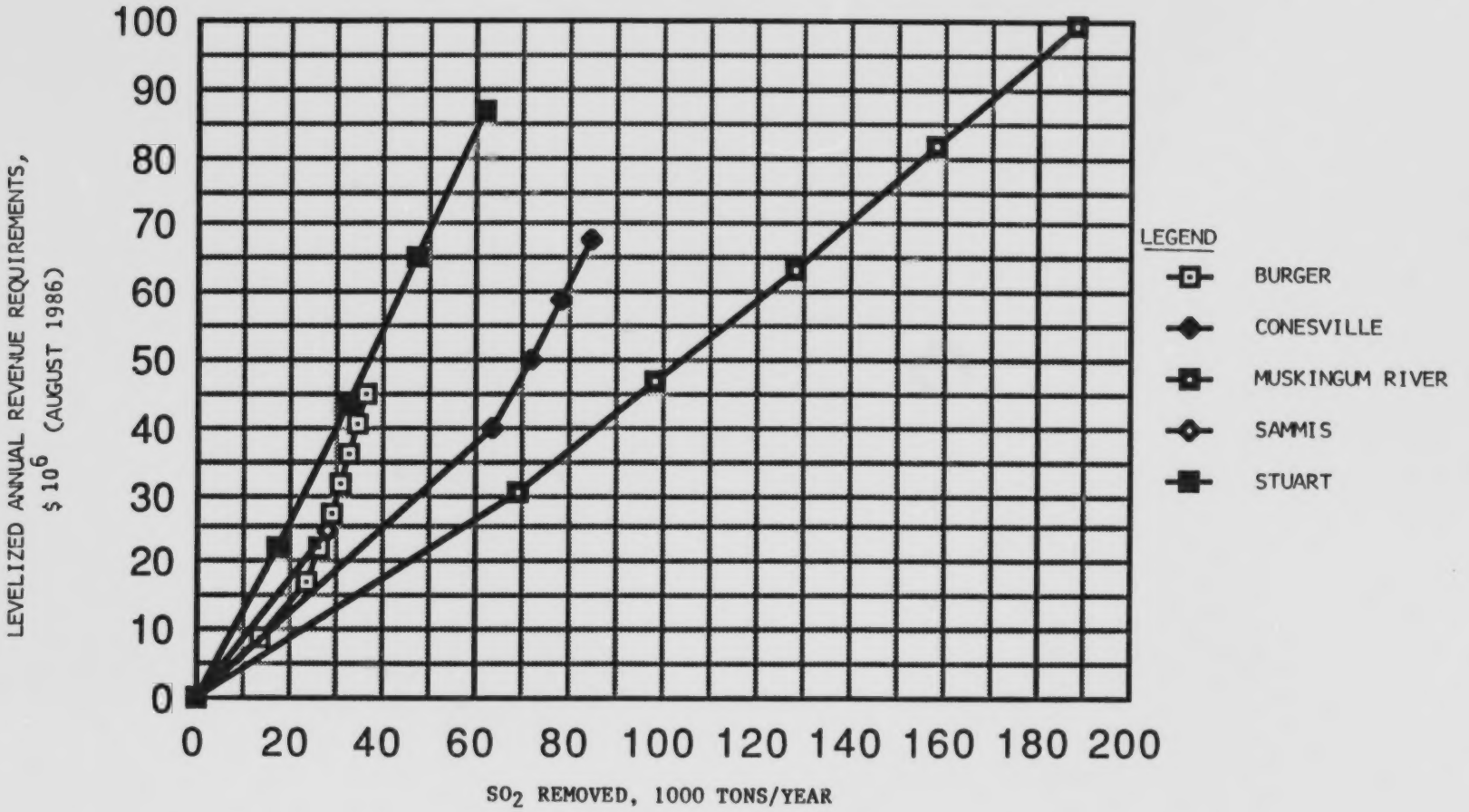

FIGURE 3. PERFORMANCE/COST ESTIMATES FOR SO_2 EMISSION REDUCTION VIA LIME SPRAY DRYING AT FIVE COAL-FIRED POWER PLANTS IN OHIO

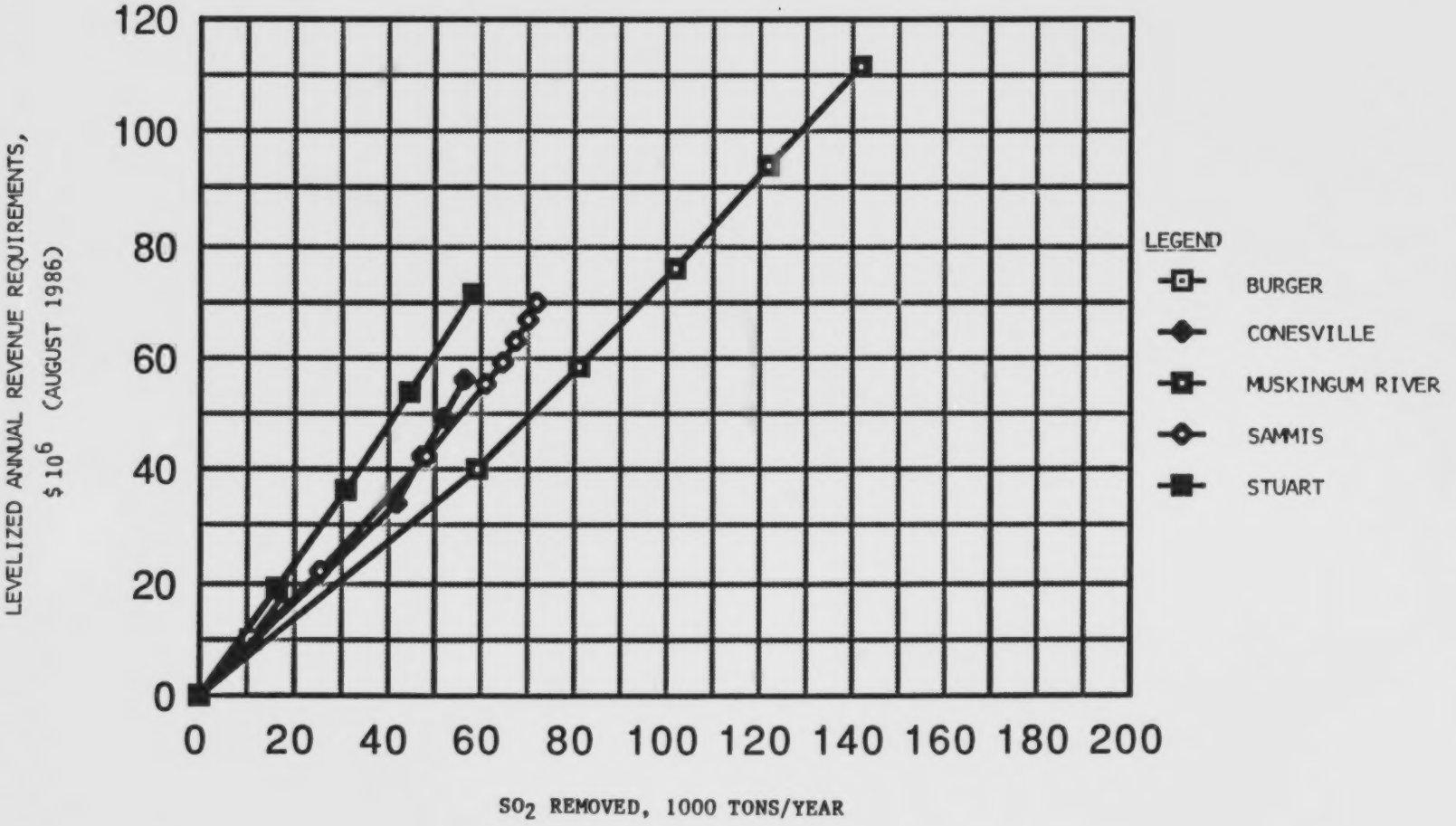

FIGURE 4. PERFORMANCE/COST ESTIMATES FOR SO_2 EMISSION REDUCTION VIA HYDRATED LIME FURNACE SORBENT INJECTION (LIMB) AT FIVE COAL-FIRED POWER PLANTS IN OHIO

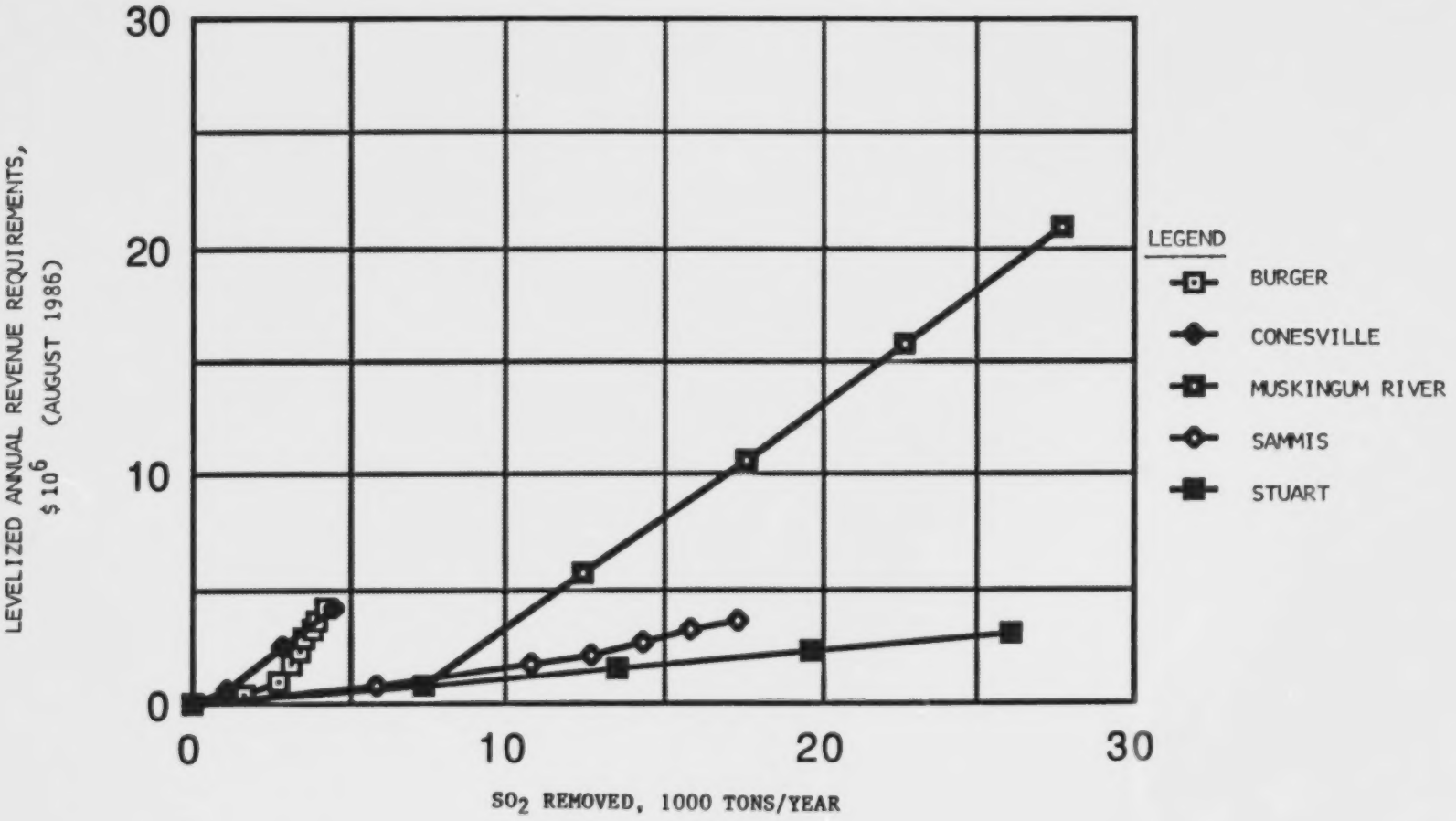

FIGURE 5. PERFORMANCE/COST ESTIMATES FOR NO_x EMISSION REDUCTION VIA LOW-NO_x COMBUSTION (LNC)/NATURAL GAS REBURNING (NGR) FOR FIVE COAL-FIRED POWER PLANTS IN OHIO

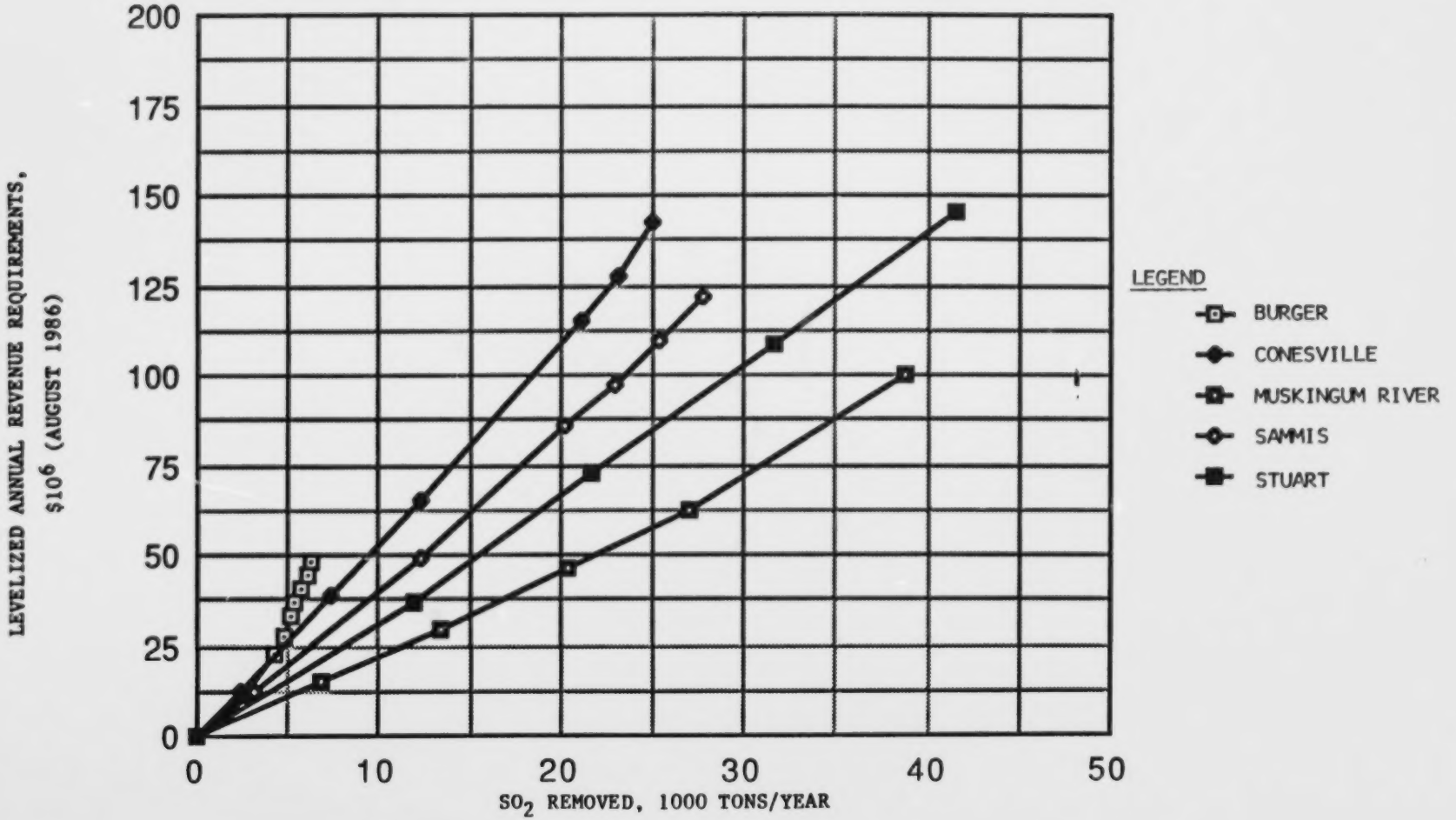

FIGURE 6. PERFORMANCE/COST ESTIMATES FOR NO_x EMISSION REDUCTION VIA SELECTIVE CATALYTIC REDUCTION FOR FIVE COAL-FIRED POWER PLANTS IN OHIO

for which applying the technology is feasible are represented. This is the reason for the steadily increasing slope (in $/1000 tons) of each curve. Depending upon the emission reduction desired for a particular plant, an electric utility could use this approach to determine a minimum cost strategy for the plant. A discussion of each figure follows.

In constructing Figure 1, a low (0.9 percent) sulfur eastern Kentucky or southern West Virginia coal was selected for each plant. Using current prices of low sulfur coal delivered to plants in Ohio, a price increase of $5/ton was assumed to simulate increased competition for low sulfur Appalachian coal. Other costs include, where applicable, modifications to coal handling/grinding and particulate control equipment. All units for three of the five plants are represented in Figure 1; the exceptions are Units 5 and 6 at Conesville, which already have FGD systems, and Units 1-4 at Sammis, which already use low sulfur Appalachian coal. As might be expected, application of coal switching at the higher sulfur coal-burning plants (Burger, Conesville, Muskingum River) shows lower costs per ton of SO_2 removed than the moderate sulfur coal-burning plants (Sammis, Stuart).

In constructing Figure 2, magnesium-enhanced lime FGD, removing 90 percent of the SO_2 emissions, was assumed to be applied (where feasible) to each plant. For Burger, FGD was assumed to be applied to two combinations of generators, Units 1-3 and 4-5. For Conesville, a combination of Units 1 and 2 was assumed, while Units 3 and 4 were assumed to have separate FGD systems (Units 5 and 6 already have FGD). For Muskingum River, a combination of Units 1-4 was assumed, while Unit 5 was assumed to have a separate FGD system. For Sammis, FGD was assumed to be applied only to Units 6 and 7; as the note on Table II indicates, severe spatial limitations prevent application on Units 1-5. The most cost-effective generating unit at each plant for application of FGD was the newest and largest. Furthermore, the cost-effectiveness of applying FGD to the units at each plant was almost invariably inversely proportional to the age and/or size (generating capacity) of the unit. This is not surprising, since the newer, larger units typically have a higher capacity factor because of their lower costs for generating electricity.

As noted in the discussion on Figure 1, the higher sulfur coal-burning plants with FGD showed lower costs per ton of SO_2 removed than those burning moderate sulfur coal. However, it is interesting to note that, when FGD is assumed to be applied to Burger Units 1-3 and Conesville Units 1-3, the cost-effectiveness (slope of the curve) is about the same as for applying FGD to Sammis and Stuart. This is because of the low capacity factor of these units (29-37 percent).

In constructing Figure 3, lime spray drying (LSD) was assumed to be applied (where feasible) to each plant. The estimated performance of the LSD systems varied from unit-to-unit and from plant-to-plant. For example, the SO_2 removal at Stuart averaged about 53 percent because of the low (115°C) air heater exit temperature, while the average for the other four plants ranged from 69 to 76 percent. Unlike the cost estimates for FGD,

no combinations of generating units at any of the plants were assumed. For Sammis, only Unit 7 was evaluated because of the severe spatial limitations discussed earlier. Except for Conesville Units 5 and 6, all units at the other four plants were evaluated. Existing or upgraded electrostatic precipitators (ESPs) were assumed for particulate control downstream of the spray dryers. As noted with the FGD estimates above, the newer and larger generating units were the most cost-effective for application of LSD. In addition, a major feature of Figure 3 is the fact that the combination of the cost of upgrading ESPs at Burger and the low capacity factors for Burger Units 1-3 caused these units to be the least cost-effective represented in the figure. Also, the low capacity factors for Units 1-3 at Conesville caused these units to have a cost-effectiveness similar to the lower sulfur coal burning units at Stuart; this effect was also noted for the FGD applications in Figure 2.

In constructing Figure 4, boiler injection of hydrated lime (LIMB), removing 50 percent of the SO_2 emissions (at 25 percent lime utilization), was assumed to be applied (where feasible) at each plant. For Burger, only Units 5 and 6 were evaluated because the top-fired Sterling drum boilers serving Units 1-6 prevent the application of this technology. Except for Units 5 and 6 at Conesville, all units at the other four plants were evaluated. Existing or upgraded ESPs were assumed for particulate control. Because of the relatively lower capital cost of the LIMB process compared to FGD and LSD, the operating costs tend to be dominant. This diminishes the cost-effectiveness of the high sulfur coal-burning plants and enhances the cost-effectiveness of the low or moderate sulfur coal-burning plants (relative to FGD and LSD).

This effect is apparent in Figure 4, in which the slopes of the Conesville and Muskingum River curves are greater than the curves for those plants in Figures 2 and 3. On the other hand, the slopes of the Sammis and Stuart curves in Figure 4 are lower than the curves for those plants in Figures 2 and 3. The overall effect is to bring all of the curves close to one another; i.e., the variation in cost-effectiveness for LIMB from plant-to-plant is much less significant than it is for FGD or LSD.

In constructing Figure 5, a combination of low NO_x combustion (LNC) and natural gas reburning (NGR) was assumed to be applied. The application of these technologies was assumed to vary from plant-to-plant, depending on the boiler types at each plant. Low-NO_x combustion, removing 50 percent of the NO_x emissions, was assumed to be applied to wall-fired, dry bottom boilers at which it had not already been applied; these included Units 5 and 6 at Burger, Unit 3 at Conesville, Unit 5 at Muskingham River, Units 1-4 and 6-7 at Sammis, and all units at Stuart. Natural gas reburning, removing 60 percent of the NO_x emissions and 15 percent of the SO_2 emissions (15 percent gas substitution for coal), was assumed to be applied to the six top-fired boilers (Units 1-3) at Burger, the two wall-fired, wet bottom boilers (Units 1 and 2) at Muskingum River, and all cyclone boilers--Units 1 and 2 at Conesville and Units 3 and 4 at Muskingum River.

The difference in cost-effectiveness between LNC and NGR is shown very clearly by the change in slope of the curves for Burger, Conesville, and Muskingum River, where both LNC and NGR are assumed to be applied. Note that the cost-effectiveness of NGR shown in Figure 5 does not include credit for SO_2 reduction. For example, if the horizontal axis of Figure 5 represented the sum of NO_x and SO_2 removed in 1000 tons, the last point on the Muskingum River curve would be 52,400 tons of SO_2 + NO_x instead of 27,700 tons of NO_x. This represents a significant improvement in overall cost-effectiveness compared to NO_x emission reduction alone.

In constructing Figure 6, selective catalytic reduction (SCR), removing 80 percent of NO_x emissions, was assumed to be applied to all units at all five plants, including those which already employ low-NO_x combustion. Based on the results shown in the figure, SCR is most cost-effective on large base-loaded generating units which currently have no NO_x controls. However, the costs for NO_x removal via this approach are significant.

Kentucky/TVA Plants

Data and information obtained during visits to the seven Kentucky/TVA plants described in Table III are currently being used to develop performance/cost relationships for these plants. The results of these efforts were not available for inclusion in this paper. However, these efforts are expected to be completed in the Spring of 1987.

PLANNED EFFORTS

Concurrent with completion of the Kentucky/TVA studies, the overall project results and procedures will be evaluated. The objective of this evaluation is to develop and initiate a low-cost approach to conduct plant-specific performance/cost studies for all of the top 200 SO_2-emitting coal-fired power plants. As currently envisioned, data and information on the plants will be obtained during visits to selected state agencies, utility corporate offices, and power plants.

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